ISSUE PAPER

Regulating Gas in B.C. to Achieve 2030 and 2050 Climate Goals

Recommendations on the GHG Reduction Standard, DSM Regulation, and FortisBC's revised renewable gas program

Colton Kasteel, Tom-Pierre Frappé-Sénéclauze | November 2022

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About the Pembina Institute

The Pembina Institute is a national, donor-supported think tank that advocates for strong, effective policies to support Canada's clean energy transition. We employ multi-faceted and highly collaborative approaches to change. Producing credible, evidence-based research and analysis, we consult directly with organizations to design and implement clean energy solutions, and convene diverse sets of stakeholders to identify and move toward common solutions.

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Executive summary

Renewable gaseous fuels will play a role in B.C.'s long-term decarbonization, but their origin, end-uses and level of prominence in the long-term provincial energy mix are uncertain. The regulations developed as part of the CleanBC Roadmap to 2030, currently in design, will have a significant impact on the use of gaseous fuels and the future of the gas-distribution grid in B.C. The purpose of this paper is to respond to FortisBC Energy's (FEI's) B.C. Utilities Commission (BCUC) application and summarize the Pembina Institute's perspective on the GHG Reduction Standard (GHGRS) and proposed changes to the B.C. Demand-Side Measures Regulation.

The Pembina Institute's key takeaways on the current and future state of renewable gases in B.C. are:

- B.C. has two main energy distribution systems: the gas delivery grid and the electricity grid. Both can deliver low-carbon energy, and both should be leveraged to accelerate the energy transition.
- Due to technological and market uncertainties, it is unclear what quantity of renewable gases will be available to British Columbians. Projections for domestic renewable gas supply show that it will not be sufficient to meet the thermal load currently supplied by fossil gas.
- On the electricity side, current projections from BC Hydro stop in 2040. As electrification ramps up across all sectors, we can expect a rapidly growing load between 2040 and 2050. B.C. has ample resources in wind and solar, but storage and distribution will be limiting factors. It is important to consider how a decarbonized gas distribution system can help electrification by providing capacity and storage. This usage can probably be supported without major upgrades to the gas distribution system, other than enabling certain segments of it to carry larger fractions of hydrogen.
- Electrification should be prioritized in sectors that have readily available electrification solutions — such as new buildings and baseload heat for existing buildings — to ensure the most effective use of limited renewable gas resources. This will help ensure renewable gases are cost-competitive to decarbonize hard-to-electrify sectors such as industrial processes requiring high heat (e.g. cement, oilsands) and heavy-duty vehicles (e.g. long-haul trucking). Renewable gases could also be leveraged to minimize the need for electrical infrastructure upgrades by providing power and heat during the coldest days of the year in local combined heat and power peaking plants and/or in hybrid heating systems.

- B.C. needs to reduce its consumption of all types of gaseous fuels through a combination of energy efficiency and fuel-switching to limit the risk of fossil fuel lock-in. B.C. also needs to invest in the development of a greater domestic supply of renewable gases.
- Regulations announced in the CleanBC Roadmap to reduce emissions from gas utilities and ban incentives for gas-fired appliances are critical climate policies.
- The subsidization of renewable gas consumption in new homes and buildings works against this best use of renewable gas principle and the intent of the proposed GHGRS.
- The existing gas distribution system will need to look substantially different than it does today to fit in B.C.'s net-zero pathway. The business case for low-carbon gas as a peaking fuel needs to be better understood at the site level and the system level. Uptake for low-carbon dual fuel systems and base-load fuel switching by consumers will depend on how well rates capture the value offered by peak-management strategies.

Based on these considerations, we recommend:

- The province introduces the ban on incentives for gas appliances by end of 2022, even if appliances were to be using 100% renewable gases. The minister should issue a directive to the BCUC requesting it works with the utilities to ensure the DSM plans that are under review are amended to meet these new regulations.
- FEI is granted an extension to revise its 2022 Long-Term Gas Resource Plan (LTGRP) so that it incorporates the cap on gas utility emissions announced in the Roadmap to 2030.
- Until the LTGRP is revised to incorporate the GHGRS there should be no new spending by the utility to expand gas delivery infrastructure. Until plans are in place to meet the GHGRS, utilities should only be allowed expenditures to maintain the system, develop new renewable gas resources and expand demand-side management offerings to offer deep retrofit incentives.
- The BCUC allows FEI to provide renewable gaseous fuels as a heating source for some existing buildings — but at the full marginal cost.
- The province should clarify standards and methodology for utilities to quantify the carbon content of renewable gases and track their environmental attributes to ensure they are not double-counted if traded separately from the molecules. This methodology should be included in the GHGRS and the Greenhouse Gas Reduction Regulation (GGRR) before the latter is revised to increase the annual allowable blend of renewable gases in the distribution system above 15%.

- FEI should articulate how the gas delivery system could provide peak heat load rather than base heat load, and work with B.C. to analyse where reliance on gas for heat peaks would be most favourable given electrical capacity constraints and how such value should be monetized, and from this assess where/ when trimming off the gas grid would be economically favourable.
- FEI should present a renewed vision for its business model, shifting from capital investments for the delivery of base heat loads, to focus instead on the production of renewable natural gas (RNG) and hydrogen, the support of gas for transportation, the delivery of deep retrofits, and the provision of low-carbon heat as a service, leveraging both electric and hybrid high-performance systems.

1. Introduction

In 2021, new policy objectives were announced to help close the gap to B.C.'s 2030 emissions goals, along with regulatory changes that affect the use and generation of gaseous fuels in B.C.[1] Announced initiatives include:

- An emissions cap for gas utilities of 6 Mt of CO_2e per year for 2030 (47% reduction below 2007 levels).
- A BCUC mandate to review "plans, investments and expenditures to ensure they're aligned with the GHG emissions cap and cost effective."[2]
- 100% or more efficiency standards for new space and water heating equipment by 2030.
- Performance-based carbon pollution standards for new buildings.
- Regulations to phase out gas equipment incentives, "support market readiness for future standards and codes, place more emphasis on electrification, and to ensure affordability for households and businesses."[3]
- Increased stringency of the Low Carbon Fuel Standard (LCFS), requiring fuel suppliers to reduce average carbon intensity by 30%, by 2030.[4]
- Updates to the GGRR, allowing for: the price cap to increase with inflation; the share of FEI's gas content that is renewable to rise to 15%; new pathways for utilities to secure renewable gas supply.

In 2021, FortisBC Energy Inc. (FEI) filed an application with the BCUC for a revised renewable gas program, which proposes to:[5]

- Provide 100% renewable gas for new residential construction, at the same cost as the fossil gas delivered to other customers.

[1] Province of British Columbia, *CleanBC Roadmap to 2030* (2021). https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf

[2] *CleanBC Roadmap to 2030*, 29.

[3] *CleanBC Roadmap to 2030*, 41.

[4] Related transportation policy announcements that will affect the demand for renewable gaseous fuels include: the upcoming Clean Transportation Action Plan; a commitment to introduce medium and heavy-duty vehicle sales targets (both expected in 2023); and a commitment to reduce the energy intensity of freight and goods movement by 10% (2030), 30% (2040) and 50% (2050).

[5] FortisBC, *Response to the British Columbia Utilities Commission (BCUC) Staff Information Request (IR) No. 1*, (2022). https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65233_B-12-FEI-response-to-BCUC-Staff-IR1.pdf

- Deliver a minimum blend of 1% RNG in 2024, rising over time, to all FEI customers.
- Preserve existing voluntary RNG blends of 5, 10, 25, 50 or 100%.

This issue paper responds to FEI's BCUC application and summarizes the Pembina Institute's perspective on the GHGRS and the proposed changes to the British Columbia Demand-Side Measures (DSM) Regulation.[6] We discuss how renewable gas potential in B.C., along with regulatory best practices, should inform a response to FEI's application and the design of the regulations currently being developed. Our recommendations are based on advancing equity, maximizing economic opportunity in B.C., and increasing the likelihood of B.C. meeting its climate targets in all sectors. Because not all sectors of the economy will face regulatory pressures to be decarbonized at the same time, it is worth designing policies that allow limited low-carbon renewable gaseous fuel resources to be directed to the economic sectors that need it most.

[6] Government of British Columbia, *Demand-Side Measures Regulation*, B.C. Reg. 326/2008 (2008). https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/326_2008

B.C. Ministry of Energy and Mines, *Guide to the Demand-Side Measures Regulation* (2014). https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/energy-efficiency/guide_to_the_dsm_regulation_july_2014_c2.pdf

2. Regulatory context for renewable gas resources in B.C. and priority end-uses

In 2011, the BCUC approved FEI's RNG program which provides customers with the option to purchase gas with different blends of RNG.[7] The GGRR was subsequently amended, enabling utilities to make new investments to increase the supply of RNG to up to 15% of total demand, and to allow the price cap of $30/GJ to increase with inflation.[8] With the release of the provincial hydrogen strategy and updated climate policy commitments in 2021, B.C. has set the stage for new investments to be made in domestic renewable gas production.

Several different types of renewable gases are likely to be used in B.C. as the economy decarbonizes, including RNG; green, blue, turquoise and waste hydrogen; and syngas (see Table 1 for descriptions).

Table 1. Renewable gas terminology

Term	Definition
Renewable natural gas	Biomethane is produced and captured from a variety of sources (agricultural and organic waste, forestry waste, landfills, and wastewater).
Green hydrogen	Extracting hydrogen from water, using electrolysis powered by renewable energy.
Blue hydrogen	Extracting hydrogen from natural gas, then using carbon capture and sequestration technology to store a portion of the remaining carbon.
Turquoise hydrogen	Hydrogen is produced along with solid carbon through the pyrolysis of methane.
Waste hydrogen	Hydrogen that is produced as a by-product in industrial processes is captured rather than vented.

[7] FortisBC, "How much does Renewable Natural Gas cost?" https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas/how-much-does-renewable-natural-gas-cost

[8] Province of British Columbia, "Greenhouse Gas Reduction Regulation." https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/clean-transportation-policies-programs/greenhouse-gas-reduction-regulation

Pyrolysis	Splitting the methane (CH_4) from natural gas into hydrogen and solid carbon.
Syngas	Synthesis gas (syngas), a mixture of hydrogen and carbon monoxide plus other gases, can be produced through wood gasification and further processed to hydrogen and/or methane.
Steam methane reforming (SMR)	Commercial technology that uses steam to separate hydrogen from natural gas. SMR facilities have operated to produce hydrogen for use as a feedstock for other processes such as oil refining, fertilizer, or chemical production.[9]
Auto thermal reforming (ATR)	Commercial technology commonly used in the production of ammonia and methanol. Allows the capture of carbon at higher rates than conventional SMR technology, at a lower cost. Compared to SMR, ATR has a simpler production stream, with a high concentration of carbon dioxide.[10]

2.1 Supply forecasts and technology readiness

While there are various opportunities to generate renewable gases in B.C., supply under current technologies is likely to remain much smaller than the current provincial demand for fossil gas. FEI's gas system has supplied approximately 230 PJ per year.[11] Adding the gas distributed in northern B.C. by Pacific Northern Gas (9.7 PJ)[12] and the gas used by industrial facilities upstream from the distribution system (estimated at ~180 PJ), the total end-use gas demand in B.C. is close to 400 PJ: 20% of which goes to the residential sector, 20% to the commercial sector, and 59% to the industrial sector.[13]

Studies produced by FEI focus generally on their capacity to reduce the carbon content of their ~230 PJ of delivered gaseous fuels; however, at a provincial scale, the whole 400

[9] Jan Gorski, Karen Tam Wu, Tahra Jutt, *Carbon intensity of blue hydrogen production: Accounting for technology and upstream emissions*, 1 (Pembina Institute, 2021). https://www.pembina.org/pub/carbon-intensity-blue-hydrogen-production

[10] *Carbon intensity of blue hydrogen production*, 2.

[11] FortisBC, *Annual Review for 2022 Delivery Rates* (2021), 14. https://docs.bcuc.com/Documents/Proceedings/2021/DOC_63692_B-2-FEI-Annual-Review-2022-Delivery-Rates-Appl.pdf

[12] 2021 actuals: 5.4 PJ for PNG-West and 4.3 PJ for PNG-N.E.

Pacific Northern Gas Ltd. (PNG-West Division), *AMENDED Application to the British Columbia Utilities Commission for Approval of 2022 Revenue Requirements*, March 7, 2022, 26. https://png.ca/wp-content/uploads/2022/03/PNG-West-Amended-2022-Revenue-Requirements-Application-Mar-22.pdf

Pacific Northern Gas (N.E.) Ltd., *AMENDED Application to the British Columbia Utilities Commission for Approval of 2022 Revenue Requirements*, March 7, 2022, 20. https://png.ca/wp-content/uploads/2022/03/PNGNE-FSJ-DC-Amended-2022-Revenue-Requirements-Application-Mar-22.pdf

[13] Canada Energy Regulator, "Canada's Energy Future Data Appendices." https://doi.org/10.35002/zjr8-8x75

PJ needs to be decarbonized by 2050 through a mix of conservation, efficiency, electrification and low-carbon renewable gases.

Latest projections for the potential domestic supply of renewable gas suggest 25 to 50 PJ of renewable gas could be produced in B.C. by 2030.[14] FEI estimates in its LTGRP that it would need 60 PJ of renewable gas by 2030 to meet requirements announced in the CleanBC Roadmap under its current business model.[15,] This means that even if B.C. achieves its domestic supply potential, FEI would still need to secure up to 35 PJ of renewable gases by 2030 from out-of-province markets to meet the load forecasted in its LTGRP.

The picture for 2050 is less clear. 114 to 444 PJ of renewable gaseous fuels could be generated by 2050, with blue and turquoise hydrogen representing the largest share, and RNG produced via anaerobic digestion accounting for 2%.[16] The higher range of these projections includes projects with acquisition costs up to $50/GJ,[17] at which point it will likely be more expensive than electrified heating.

RNG produced via proven technological processes (agricultural waste, municipal waste, or landfill gas capture) could yield up to 9.5 PJ per year by 2030 and 11.2 PJ per year by 2050; only 19% of potential supply in 2030 and 2.5% of potential supply in 2050. Most of the potential supply comes in the form of hydrogen and second-generation RNG from wood waste (Figure 1 and Figure 2) — technologies that have not been proven at scale. These emerging technologies are considered "wild cards"; they could come to play a role in decarbonizing the economy but present a high degree of uncertainty.[18]

[14] Envint and Canadian Biomass Energy Research Ltd., *B.C. Renewable and Low-Carbon Gas Supply Potential Study* (2022), prepared for BC Bioenergy Network, FortisBC, Province of British Columbia, 4. https://www.cdn.fortisbc.com/libraries/docs/default-source/news-events/bc-renewable-and-low-carbon-gas-supply-potential-study-2022-03-11.pdf

[15] FortisBC, *2022 Long Term Gas Resource Plan (LTGRP) Diversified Energy Future*, 26. February 2021. https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/2022-ltgrp-external-stakeholder-presentation-10feb2022.pdf

[16] *B.C. Renewable and Low-Carbon Gas Supply Potential Study*, 3.

[17] *B.C. Renewable and Low-Carbon Gas Supply Potential Study*, 4.

[18] Canadian Institute for Climate Choices, "Canada's Net Zero Future – Recommendations". https://climateinstitute.ca/reports/canadas-net-zero-future/recommendations/

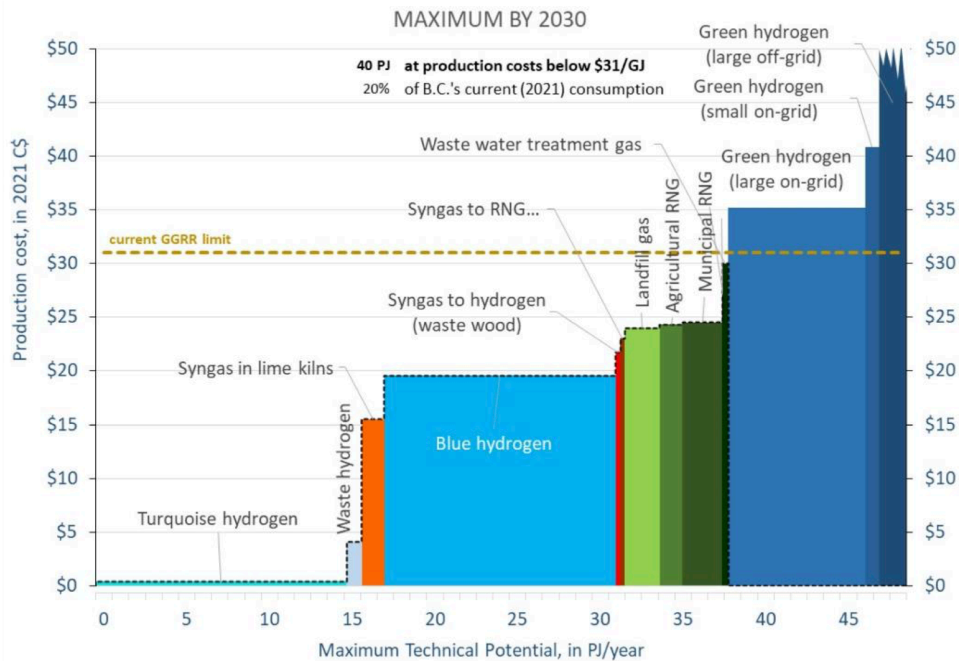

Figure 1. Production cost and technical potential of renewable and low-carbon gas in B.C. in 2030 (Maximum Scenario)

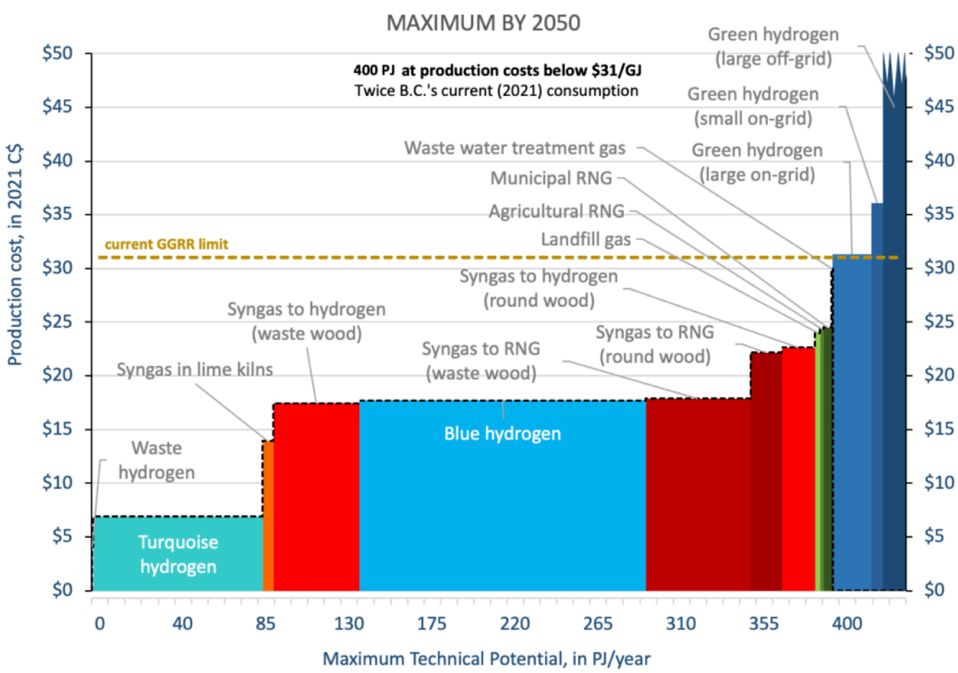

Figure 2. Production cost and technical potential of renewable and low-carbon gas in B.C. in 2050 (Maximum Scenario)

Source: Envint and Canadian Biomass Energy Research[19]

[19] *B.C. Renewable and Low-Carbon Gas Supply Potential Study,* 5.

Production of hydrogen as an energy carrier is still in its early stages. Most blue hydrogen facilities in operation today are integrated into refineries and fertilizer plants and were built before carbon pricing and meaningful climate targets called for high rates of capture. There are several production pathways for hydrogen to contribute to B.C.'s economy as a low-carbon fuel, including steam methane reforming, auto thermal reforming, and pyrolysis. Blue hydrogen needs carbon capture rates over 95% and limited upstream emissions to be considered 'low carbon'.[20,21] To address upstream methane leakage, B.C. has committed to a greater than 75% reduction in methane emissions by 2030 and near zero by 2035. High carbon capture rates above 90% have been demonstrated in other applications and several proposed blue hydrogen facilities have set carbon capture targets of 95%, but none have been built yet. In the case of turquoise hydrogen, methane pyrolysis technology needed for production is still in the prototype stage, globally.[22] FEI is currently building a pilot project in B.C. that would produce turquoise hydrogen, but it is not yet known what the carbon capture rates would be for the facility if it reaches the commercial stage.[23] Both these forms of hydrogen could be blended with natural gas to meet incremental emissions reduction goals; however, current pipeline capacity has blending limits of approximately 20%, and we currently lack a comprehensive review of the estimated infrastructure costs associated with building out a network of hydrogen distribution across the province.

Like hydrogen, second-generation RNG technology is still not commercially viable at scale. It also represents a relatively small portion of long-term renewable gaseous fuel production. Accelerating logging for energy production may face difficulty scaling up amid growing competition for wood fibre supply.

[20] *Carbon intensity of blue hydrogen production,* 8.

[21] New literature in B.C. disputes the reported carbon intensity of natural gas, suggesting that methane emissions are underreported; ongoing research is actively investigating this issue. David Tyner and Matthew Johnson, "Where the Methane Is - Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data," *Environmental Science and Technology* (2021), 55. https://doi.org/10.1021/acs.est.1c01572

[22] IEA, "ETP Clean Energy Technology Guide," Hydrogen. https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide?selectedSector=Hydrogen

[23] Financial Post, "FortisBC, Suncor to partner on Port Moody hydrogen pilot project," July 4, 2022. https://financialpost.com/commodities/energy/oil-gas/fortisbc-suncor-to-partner-on-port-moody-hydrogen-pilot-project

2.2 Priority end-uses

If the future supply of renewable gaseous fuels available to B.C. were too small to meet the current level of demand for gaseous fuels, B.C. would be best served using the limited resources in end-uses that cannot easily be electrified, to maximize chances of meeting our net-zero goal. Infrastructure investment decisions should prioritize the delivery of renewable gas towards economic sectors and end-uses where other low-carbon alternatives are not readily available.

2.2.1 Sectors

In the industrial sector, electricity cannot easily meet the demand for high-grade heat — for example, in cement production, aluminum smelting, and oilsands production. For Canada to achieve net-zero, a significant portion of renewable gas supply will need to be directed to oilsands operations, which currently account for approximately 17% of total end-use natural gas demand in Canada.[24]

In the transportation sector, it is expected that battery electric technologies can meet the needs of most medium- and heavy-duty vehicles (MHDVs) in Canada; however, for the heaviest vehicles, including long-haul trucks, hydrogen-powered fuel cells are expected to be needed. Modelling commissioned by the Pembina Institute shows that for Canada to meet its goal for 100% of new MHDVs to be zero emission by 2040, as much as 40% of HDVs will be fuel cell powered by 2040.[25]

In the building sector, renewable gases could be used to provide energy storage for peak heating.[26] This could be achieved in two ways: using renewable gas in combined heat and power plants near high-demand areas, and using renewable gas as a peaking fuel in hybrid systems (for example by leveraging legacy furnaces or boilers to supplement electric heat pump systems during the coldest days of the year). More research is needed to see which approach is optimal from a cost and carbon perspective. Opportunities for carbon capture in either of these approaches should also be evaluated, as this could yield an important source of negative emissions. Learnings could be leveraged from

[24] Total end-use for Canada was 4,183 PJ in 2020. Oilsands demand in 2020 was 1.8 bcf/day.

[25] Kasteel, Colton, Sarah McBain, Chandan Bhardwaj, *Towards Clean MHDVs: Preliminary policy solutions to decarbonize Canada's MHDVs*, 27 (Pembina Institute, 2022). https://www.pembina.org/reports/towards-clean-mhdvs-recommendations.pdf

[26] Kevin Palmer-Wilson, Tyler Bryant, Peter Wild, Andrew Rowe, "Cost and capacity requirements of electrification or renewable gas transition options that decarbonize building heating in Metro Vancouver, British Columbia," *Energy Strategy Reviews*, 42 (2022), 10. https://doi.org/10.1016/j.esr.2022.100882

other jurisdictions; in Québec for example, the gas utility Énergir and the electricity crown corporation Hydro Québec reached an agreement to encourage gas users to use gas as a peaking fuel and electrify base load, reducing the natural gas consumption of participating customers by over 70%.[27]

Given the range of low-carbon alternatives readily available to decarbonize base heating loads in buildings, we consider it a lower priority sector for the deployment of renewable gases in a net-zero world.[28] Some researchers have found that pursuing an electrification-dominant pathway for heating in existing building stock presents relative cost and energy storage challenges, compared to renewable gas.[29] The focus of reserving renewable gas molecules for hard-to-electrify existing buildings and peaking can help hedge against this risk.

2.2.2 Rate competition

Rate signals will also affect where in the economy renewable gases are used, and where electricity is preferred. Climate-target compatible scenarios modelled by FortisBC and BC Hydro all show that the total demand for gaseous fuel in buildings will decrease (Table 2). This will yield upward pressure on delivery rates. Combined with a higher cost for renewable gas and the higher coefficient of performance for electric heat pumps, this will eventually make gas heat less competitive with electrified heat.

[27] Énergir, *Hydro-Québec and Énergir: An unprecedented partnership to reduce greenhouse gas emissions*. July 2021. https://www.energir.com/en/about/media/news/partenariat-inedit-hydro-quebec-et-energir/

[28] There might be use for renewable gas in legacy institutional buildings and campuses, which can be challenging to economically electrify given the complexity of their heat delivery systems (e.g., steam systems in hospitals and universities).

[29] "Cost and capacity requirements of electrification or renewable gas transition options that decarbonize building heating in Metro Vancouver, British Columbia."

Table 2. Energy demand for four scenarios by BC Hydro and FEI

Scenario	2030 Demand			2040 Demand		
	Gas: Energy (TWh)	Electricity: Energy (TWh)	Electricity: Capacity (MW)	Gas: Energy (TWh)	Electricity: Energy (TWh)	Electricity: Capacity (MW)
BCH Reference	60.0	65.8	11,082	61.9	70.8	13,615
FEI Diversified	51.7	71.2	13,154	48.9	78.4	15,298
BCH Accelerated Electrification	35.0	75.5	13,872	25.3	82.5	15,829
FEI Deep Electrification	40.6	76.6	14,205	28.1	83.0	16,183

Data source: BC Hydro[30] and FortisBC Energy[31]

The transition to a net-zero world will also increase demand for electricity, which in turn will increase rates. Table 3 shows the expected rate increases for gas and electricity based on modelling by FEI and BC Hydro. Four load scenarios are presented here: three designed to meet climate targets (FEI's electrified and diversified pathway, BC Hydro's accelerated electrification scenario) and BC Hydro's reference scenario. To facilitate scenario comparisons, the first three are presented as increases below or above the projections for the BC Hydro reference scenario, while the BC Hydro reference case projections are presented relative to 2022 rates. Regardless of the scenario considered, rate impacts are much higher for the gaseous fuels than for electricity. This rate differential will certainly accelerate the fuel switching rate, as the lower cost of heating with an electric heat pump will quickly decrease sufficiently to justify its higher upfront cost.

[30] BC Hydro, *Fortis BC Energy Inc. and BC Hydro Energy Scenarios: BC Hydro's Submission, Phase 1*, June 6, 2022, 6. https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66884_2022-06-15-BCH-Stage1-LoadForecastResults.pdf

[31] FortisBC Energy Inc., *FEI Modelling Results* (2022), 5. https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66883_2022-06-15-FEI-Stage1-ModellingResults.pdf

Table 3. Cumulative incremental rate impacts for the four load scenarios examined

Load scenarios	F2026		F2031		F2036		F2041	
	Elect.	Gas	Elect.	Gas	Elect.	Gas	Elect.	Gas
FEI Diversified Energy (Planning)*	-0.3%	+140%	+2.1%	+175%	+2.6%	+210%	+5.2%	+267%
BCH Accelerated Electrification*	-1.5%	+140%	+1.6%	+250%	+4.2%	+260%	+8.5%	+375%
FEI Deep Electrification*	-2.8%	+120%	+3.8%	+125%	+6.0%	+110%	+6.0%	+92%
BCH Reference Load Forecast (% relative to 2022 rate)	N/A	+25%	N/A	+40%	N/A	+50%	N/A	+60%

* Relative to the BC Hydro Reference Load scenario

Data source: BC Hydro[32] and FortisBC Energy[33]

2.2.3 Uncertainty

There is still a fair amount of uncertainty regarding the demands on the grid between 2040 and 2050. This uncertainty will impact both the feasibility of meeting demand using only clean, made-in-B.C. power, as well as the cost of the electricity. There is a significant amount of electrification accelerating during the final decade to reach net-zero that the current IRP does not cover. This type of rapid increase in demand could stress the electricity system significantly, which would dramatically increase costs, supply and distribution needs.

When considering the future needs for B.C.'s gas distribution system, policymakers need to consider not only up to 2040, but also what an optional net-zero system that leverages these two energy distribution systems could look like. Furthermore, consideration should be given to whether there is a regional component to plan for. For

[32] Electricity rate impacts from: BC Hydro, *FortisBC Energy Inc. and BC Hydro Energy Scenarios, BC Hydro Submission: Stage Two*, Table 4, 15. https://docs.bcuc.com/Documents/Proceedings/2022/DOC_67460_2022-08-12-BCH-Stage2-Submission.pdf

[33] Gas rate impacts for residential RS1 rate, expressed relative to their value in the 'BC Hydro reference case scenario' (chosen as a baseline to simplify reading), *FortisBC Energy Inc. and BC Hydro Energy Scenarios, FEI Submission: Stage Two,* Figure 6 (interpolated), 20.

example, should we have areas with full electrification and intentional pruning of the gas grid to avoid maintaining assets that serve only a few customers, and/or areas with dedicated new hydrogen grids?

Clarity on where renewable gases will be of most use and fetch the highest price would help inform which sections of the gas distribution systems are worth maintaining and where there would be value in a coordinated pruning of the grid.

In the rest of this issue paper, we review three policies and processes being discussed in 2022 that will shape the evolution of gaseous fuel distribution and generation in B.C. for years to come. It is not necessary to settle on the 'best use of renewable gas' discussion briefly outlined above to optimize the design of the GHGRS and GGRR, but we find it helpful to keep in mind where renewable gases are most likely to play a role in a decarbonized future to pressure-test these regulations and ensure they do not lead to unintended consequences.

3. Regulations affecting gas end-uses

There are three main regulatory processes currently underway that will shape the use of gaseous fuels in B.C. and the future of the gas distribution grid. We discuss them below, summarizing for each where the process is at, what is being proposed, and the Institute's perspective on the issue.

3.1 GHG Reduction Standard

Context

The intention to set a cap on GHG emissions from gas utilities was announced in the CleanBC Roadmap to 2030, in November 2021. The government is now in the process of developing legislation and regulations for its implementation. The gas utilities are proactively being consulted, but no draft of the policy has yet been circulated publicly and there has not been a public comment period yet.

What's being proposed

In the CleanBC Roadmap to 2030, the provincial government committed to introducing a GHG emissions cap for utilities, by which they would have to reduce their total end-use emissions to a maximum of 6 Mt of CO_2e per year by 2030 — 47% below 2007 levels. Utilities would be able to combine DSM reductions and decarbonization of the gaseous fuel mix to meet this outcome.

Pembina Institute's view

- The cap is a nation-leading policy — but like other policies aiming for a 2030 target, it needs a clear accountability process to ensure actions are set in motion in the short and medium term to meet the target.
- Its focus on absolute emissions reductions, rather than setting a relative percent in GHG reduction based on total production, is paramount to climate accountability and will simplify the compliance and verification process.
- The regulation should require FEI to provide a plan for how the target will be met, with annual interim targets that can be used to track progress, along with

complementary measures specified in the plan to be taken if the metrics are not on track.

- A full life cycle methodology should continue to be used to calculate emissions from different renewable gases (and from fossil gas supply), accounting for the carbon intensity of the fuel production and the methane leakage in production and distribution. Depending on the variability in the carbon intensity of different operators or facilities, the carbon intensity of the different fuels should be based on the B.C. average for a given technology, unless operators or facilities can demonstrate a lower intensity using proven measurement-based methods. This would also require a system to track the origin and end-uses of fuel generated by each plant.
- In combination with B.C.'s commitment to increase the carbon tax to $170/tonne by 2030, the combined policy portfolio of DSM regulations, emissions limits and the carbon tax will more closely reflect the social cost of gas consumption and improve the business case of deep retrofits and electrification investments.
- There should be a freeze on line extensions until the 2030 plan and accountability process is in place, unless the utility can show clearly that the upgrades are compatible with the 2030 objectives. DSM expenditures, as long as they are compatible with the changes in the DSM regulations and the ban of fossil fuel equipment, should continue and be approved as needed by the BCUC.
- The government should issue a directive to the BCUC to postpone the review of the 2022 Long Term Gas Resource Plan[34], so that it can be amended and filed jointly with a plan to align with B.C.'s 2030 climate targets. This will avoid further gas delivery infrastructure from being built, which might not be needed under a lower-load scenario.

Further considerations for B.C. and utilities

Similar to B.C.'s self-sufficiency requirement for electricity, should there be a made-in-BC requirement for renewable gases?

Currently, the BCUC has indicated that the environmental attributes of renewable gases can be separated from the molecules themselves and purchased outside of B.C. to meet

[34] Fortis BC, "2022 Long Term Gas Resource Plan." https://www.fortisbc.com/about-us/corporate-information/regulatory-affairs/our-gas-utility/gas-bcuc-submissions/fortisbc-energy-inc.-gas-submissions/LTGRP/2022-long-term-gas-resource-plan

the intent of GGRR.[35] However, a revised direction from government could change this. The Pembina Institute believes a 'made-in-B.C.' requirement should be included in the new GHGRS.

This approach would be akin to how B.C. manages electricity, and it would maximize local economic development opportunities and help avoid a potential over-reliance on imported gas supply. This is important both for B.C.'s energy resiliency and the climate. FEI has been a market maker for renewable gas in North America and B.C.'s early mover advantage enables us to capture low-cost contracts for generation across North America; however, these resources will eventually be needed to facilitate a low-carbon transition in the jurisdiction where they are situated as well. Energy security and resiliency are important considerations for B.C. as it deliberates on the optimal decarbonization pathways to 2030, 2040 and 2050. Prioritization of local renewable gas development can help hedge against long-term import supply risks. With a low population density, plentiful natural resources and a strong labour force in the resource economy, B.C., of all regions, should aim to meet its renewable energy needs locally. In the short-to-medium term, to protect market stability, there may be a rationale for grandfathering in the contracts that are currently under negotiation. However, any other import contracts should be limited to short-term contracts, to be replaced by domestic resources as they become available, with specific domestic production targets set for 2035 and 2050.

FEI is nearing the maximum 15% target for renewable gas set in the GGRR. It would be appropriate to update the GGRR ahead of the GHGRS legislation and regulation to increase this cap and allow the utility to secure more renewable gas resources as soon as possible, but a 'made in BC' requirement should be added to the GGRR to ensure the increased supply brings more economic and energy self-sufficiency benefits to B.C.

Methane leakage rates and the efficiency of carbon capture of blue hydrogen remain in dispute; should B.C. hedge against the risk of high carbon intensity from blue hydrogen?

Blue hydrogen is the largest potential source of renewable gas in B.C.,[36] yet its status as a 'low carbon' gas is uncertain; we are still waiting on clarity from ongoing studies to identify whether blue hydrogen can be a viable source of deep emissions reductions. Uncertainty in the carbon intensity of different renewable gas streams increases the risk

[35] BCUC, *Inquiry into the Acquisition of Renewable Natural Gas by Public Utilities in British Columbia: Phase 1 Report*. 2022. https://docs.bcuc.com/Documents/Other/2022/DOC_67314_Final-RNG-Report.pdf

[36] *B.C. Renewable and Low-Carbon Gas Supply Potential Study*, 3.

of locking in carbon, if investment in the gas transmission and distribution system continues under the notion that blue hydrogen will perform to the standard necessary for deep decarbonization.[37]

Until there is a path towards scaled low-carbon blue hydrogen with clear cost advantages to electrification, any plan that presumes the fuel will help meet B.C.'s targets should be questioned. Where blue hydrogen is considered seriously as a solution — for example, blended with natural gas in the short term or playing a larger role post-2040 — guardrails should be established to ensure the reliability of its carbon content. Energy suppliers need to demonstrate ultra-low-carbon blue hydrogen before we start planning to rely on it as a climate solution for B.C.

How can gas utilities assess the value to shareholders, society and customers to decommission certain branches of the gas distribution system?

Electrification poses a significant business risk for gas utilities and ultimately to their customers, yet the latest FEI LTGRP did not explicitly explore a phase-down scenario for the gas utility. We need a more rational exploration of the rate and bill impact of a planned pruning of the distribution tree to understand the most cost-effective and least disruptive ways to facilitate such a transition, were it to occur. Such a transition could happen quickly and see customers rapidly shift towards electric heat solutions once certain thresholds are passed:

- as lower throughput volume translates into a higher distribution cost per GJ delivered
- as the cost of renewable gases increases while low-hanging sources get depleted
- as the performance of electric heat pumps increases
- as the contractor base able to install them grows.

The B.C. Ministry of Energy, Mines and Low-Carbon Innovation (EMLI) should provide a clear directive for natural gas utilities to consider a phase-down scenario in their LTGRP, and to evaluate both costs and business opportunities related to the decommissioning of gas lines. This would ensure customers get appropriate advance notice of such disconnection, and that electricity utilities can plan for the additional localized load in a proactive and integrated manner.

[37] *Carbon intensity of blue hydrogen production,* 8.

3.2 Demand-Side Measures Regulation

Context

B.C.'s DSM Regulation clarifies what utilities must include in an energy efficiency portfolio and the energy efficiency or demand-side measure expenditures that can be recovered on the rate-paying base. New regulatory changes were announced in the CleanBC Roadmap to 2030 and are now being drafted by EMLI. Like other regulations, these can then be adopted by ministerial order. We expect these new regulations to inform the next DSM plans by BC Hydro and FEI.

Both BC Hydro and FEI's current DSM plans extend to 2022;[38] BC Hydro's next DSM plan (F2023 to F2025) was filed in December 2021[39] and FEI filed an interim plan for F2023.[40] All of these will be reviewed by the BCUC based on the current DSM regulations unless a ministerial order requests otherwise. Without this political direction, the new regulations would not be effective until 2024. Adjustments to the DSM plan to respond to changes to DSM regulations could, however, be brought forward voluntarily at any time as amendments.

What is being proposed

The CleanBC Roadmap announced the elimination of incentives for "conventional gas-fired heating equipment such as furnaces and boilers" and the addition of an "internal price on carbon to evaluate electrification initiatives in regulatory applications."[41]

Residential DSM programs that meaningfully reduce GHG emissions can have an upfront cost greater than the energy savings they generate. Including a more meaningful cost for carbon pollution will make it possible for utilities to defend the savings generated by energy efficiency measures, particularly programs that may not pass a cost resource test otherwise. This builds on the approach offered by the Modified Total Resource Cost test (mTRC), which already provides some means to defend a

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[38] https://www.fortisbc.com/about-us/corporate-information/regulatory-affairs/our-gas-utility/gas-bcuc-submissions/fortisbc-energy-inc.-gas-submissions/C-EM

[39] https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65190_B-10-BCH-F23-25-DSM-Expenditure-Schedules.pdf

[40] "DSM Expenditure Plans Update & Consultation", slide 19, presented to the Energy Conservation Advisory Group on May 4, 2022.

[41] *CleanBC: Roadmap to 2030,* 30, 41.

portion of DSM expenditure with a cost test that better represents the social benefits of DSM programs.[42]

Pembina Institute's view

- The ban on incentives is an important policy that helps recognize the true cost of subsidizing and "locking in" new gas-burning infrastructure rather than funding the transition to electrification solutions that are readily available and better equipped to deliver emissions reductions.
- Government should implement the ban in the next year to limit artificially subsidized new installations and ensuing infrastructure lock-in. This is an urgent priority as new gas furnaces and boilers installed in the near term are expected to near retirement only by 2040, and many systems remain in use well past their expected lifespan.
- The ban on incentives for gas appliances should be maintained in single-family dwellings, even if a customer were to commit to 100% renewable gas since there is no guarantee that the subsequent owner of the dwelling would commit to this rate.
- The internal carbon price should be considered not only for electrification incentives, but also for programs that aim to achieve high GHG reductions while maintaining their original fuel systems, such as the deep energy retrofit pilot being pursued by FortisBC.

3.3 FEI revised renewable gas program

Context

In October 2020, FEI submitted to the BCUC that it would propose a revised renewable gas program. The application was filed in December 2021.[43] There was a first round of information requests in April 2022, and a second round of information requests took place in the summer. There is no set timeline for the final decision by the BCUC, but it is expected in 2023.

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[42] Katherine Muncaster, Andrew Pape-Salmon, Sarah Smith, Mark Warren, "Adventures in Tweaking the TRC: Experiences from British Columbia," *2012 ACEEE Summer Study on Energy Efficiency in Buildings* (2012) https://aceee.org/files/proceedings/2012/data/papers/0193-000258.pdf

[43] BC Utilities Commission, "Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program." https://www.bcuc.com/OurWork/ViewProceeding?ApplicationId=807

What is being proposed

FEI is proposing to deliver 100% renewable gas to new residential connections; deliver a minimum blend of 1% RNG in 2024, rising over time, to all FEI customers; and preserve existing voluntary RNG blends of 5, 10, 25, 50 or 100%.

The proposed tariff for new connections would guarantee 100% renewable gas for the life of the building, offered at the cost of conventional natural gas plus the cost of the carbon tax. This tariff would be tied to the building, rather than the customers, and would apply to new construction and retrofits, if the building was not previously connected to a service line. The difference between the cost of the renewable gas and the cost of fossil gas would be spread across the ratepayer base.[44]

Pembina Institute's view

- FEI's proposal is neither a good rate policy, nor a good climate policy.
- The program for new residential customers subsidizes and artificially incentivizes new connections to the gas grid, at the expense of all other customers.
- In an environment where domestic production potential is not certain to reach high levels and continental competition for imports will undoubtedly grow, we should approach the use of renewable gas resources judiciously. As articulated in Section 2, of all economic sectors that could benefit from this low-carbon fuel, new construction is likely the one where other low-carbon alternatives are the most easily implemented. Directing rare renewable gas resources to this sector will make it much harder to decarbonize industrial and transportation end-uses, which will face much higher costs for renewable gas resources.
- Before further extending the gas distribution infrastructure, FEI should first demonstrate how it can meet the 6 Mt limit with the current customer base. Subsidizing the expansion of gas service to new construction and retrofits increases the risk of gas lock-in and the risk of not meeting the proposed targets.
- We do support the proposal to provide a lower-GHG mix of gas to all residential customers and recover that cost on the ratepayer base. This has the merit of aligning the climate benefits with the cost signals, thus internalizing some of the externalities.

[44] FortisBC Energy Inc., *Comprehensive Review and Application for Approval of a Revised Renewable Gas Program,* 100. https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf

- There is merit in also providing a 100% renewable rate for existing customers, at the full cost of renewable gas. This could provide an alternative to offsets for companies or institutions that have carbon reduction goals, and allow a price-transparent way of exploring the possibility to use renewable gases as a peaking fuel to reduce the cost of electrification. The other voluntary blends should be abolished as they offer no long-term avenue to meeting reduction targets.

Further considerations for B.C. and utilities

Should the cost of new connections to the natural gas grid be paid for more fully by the entity connecting, and less spread across the rate?

In Edmonton, new connections to the gas network must pay large fees to connect,[45] while in B.C., customers signing up with FEI pay significantly less.[46] This acts as an additional subsidization for new connections. When comparing electrified against gas-powered new construction in Edmonton, there is a much fairer market competition as a result of a similar treatment between connection costs.

The government of B.C. should consider connection fees as another mechanism to steer customers towards low-carbon options, first by ensuring new customers pay for the full cost of connection to fossil gas, and then by allowing the providers of low-carbon energy supplies (renewable district energy systems or electricity) to redistribute connection costs across their ratepayer base.

[45] ATCO Gas, *Charges for Service Line Installations* (2022). https://www.atco.com/content/dam/web/for-home/natural-gas/natural-gas-schedule-rate-poster-north.pdf

[46] FortisBC, "Getting natural gas: it's easier than you think." https://www.fortisbc.com/services/natural-gas-services/getting-natural-gas-its-easier-than-you-think

4. Discussion

Renewable gaseous fuels will play a role in B.C.'s long-term decarbonization, but the province has yet to determine where they will be best used, and what policies can be put in place to steer towards this optimal result.

Scaling the domestic supply of renewable gaseous fuels contains many uncertainties over technological development and resource availability, and government policies and programs should aim to reduce this uncertainty. RNG, syngas and hydrogen will play important roles to decarbonize B.C.'s economy, particularly in use cases where no near-term cost-effective electrification technologies currently exist. Because different sectors face different policy pressures to decarbonize, nothing guarantees that sectors which could most benefit from renewable gas will be in market in time to capture early supplies of renewable gas. To aim for the safest and most cost-effective path to meeting our climate targets**, government and utilities must ensure that policy and rate drivers stimulate renewable gas markets in hard-to-electrify sectors first.**

Conversely, B.C. should plan to scale down consumption of gas in sectors where immediate electrification solutions exist, like new homes and buildings. FEI's revised renewable gas program would work against this notion and be a step back in provincial climate policy. The other regulations discussed in this paper will play an important role in clarifying the context within which utilities can plan to optimize their business opportunities and minimize costs for ratepayers.

There are currently two potential models for how FortisBC, B.C.'s main natural gas distribution company, could adjust to be relevant in a low-carbon economy. The simplest of these two models is the one primarily advanced by the utility, focusing on 'drop-in fuels': this keeps the utility's core business model as-is, ramping up DSM expenditure to minimize demand while maintaining growth in grid connections, and shifting share of total fuel distributed to homes and businesses from fossil gas to renewable gas over time. This would require a significant portion of renewable gas to be sourced from outside B.C. to keep the gas system competitive with electricity.

There are some significant flaws with this approach, as it creates a risk of carbon-intensive infrastructure lock-in; if climate policies were to be changed, or simply not adhered to, gas utilities could continue distributing fossil gas beyond 2030 and 2050. By dedicating the majority of B.C.'s renewable gaseous fuels to buildings, this model also increases the chance of carbon-intensive infrastructure lock-in in other sectors of the economy. Relying on imports creates a long-run economic leakage risk that is not optimal for the B.C. economy, increasing the province's vulnerability to competition and worsening our trade balance. Furthermore, this scenario may be detrimental to the global decarbonization effort, by allocating rare low-carbon gaseous resources to first movers rather than to hard-to-decarbonize sectors and regions.

In contrast, an alternative model for gas utilities would see them invest instead in local production of renewable gases, deep energy retrofits and even in electrification services providing heat as a service. Areas where continued gas service makes sense for peak management should be targeted by working in collaboration with BC Hydro, focusing on the use of renewable gas as a peaking fuel in areas that face capacity constraints and barriers to heat pump uptake. This warrants exploring the cost effectiveness of a targeted pruning of the gas delivery grid. This business model has not been explored openly by the utility and does feature significant innovation, regulatory and technological risk for the company. However, it could provide a very valuable template for the sustainable transition of a gas company in a regulated monopoly context and could ensure the continued economic success of an important B.C.-based company.

A clear regulatory framework set by the province is key to facilitating the establishment of such a business model. Direction from this framework has been set in past amendments to the GGRR, which allowed FEI to own renewable gas production facilities; and in CleanBC through the emissions cap for utilities, new regulations for DSM expenditures, and new regulations for buildings and heating equipment. The success of these policies will depend on their timely implementation and holding firm on the ambition set in CleanBC when faced with pushback from regulated companies.

FEI argues that new connections and ongoing investments in infrastructure expansions are necessary to generate sufficient revenues to remain a viable business. We have yet to see detailed public analysis that tests this theory and reviews alternative business models for the utilities. What would the business model for a gas utility look like if gaseous fuels shifted away from providing base load heating in B.C., and instead shifted to a peaking measure, whether in buildings or in peaking plants? The business agreement reached between Hydro Québec and Énergir provides an interesting model of how gas can be used as a peaking fuel rather than base load. Leveraging the existing gas-distribution infrastructure may be needed where the cost of electric infrastructure upgrades are too high, but this needs to be assessed at a system level, not on a site-by-site basis as is currently the case.[47]

Prioritizing electrification in the sectors where cost-effective and technologically available solutions exist helps hedge against both the supply and emissions intensity risks of large-scale dependence on 'wild card' renewable gases, such as blue hydrogen and cellulosic RNG. We recommend that the priority should be on rapidly installing predictable and low-cost infrastructure, while continuing R&D and commercial deployment of renewable gas generation. Regardless of the sector in which renewable gases end up being used, if they are indeed produced with minimal emissions, they will play an important role in the decarbonization of B.C.'s economy. But for this sector to grow, the province must continue stimulating domestic demand for renewable gases and prioritize in-province generation over the purchase of environmental attributes for renewable gas produced outside the province.

4.1 Recommendations

- The province should introduce the ban on incentives for gas appliances by end of 2022, even if appliances were to be using 100% renewable gases. The minister should issue a directive to the BCUC requesting it work with the utilities to ensure the DSM plans that are under review are amended to meet these new regulations.
- FortisBC Energy should be granted an extension to revise its 2022 Long-Term Gas Resource Plan so that it incorporates the cap on gas utilities emissions announced in the Roadmap to 2030.
- Until the Long-Term Gas Resource Plan is revised to incorporate the GHGRS there should be no new spending by the utility to expand gas delivery infrastructure. Until plans are in place to meet the GHGRS, utilities should only be allowed expenditures to maintain the system, develop new renewable gas

[47] FortisBC has conducted such system-wide cost comparison between an 'electrified' and a 'diversified' (e.g., with buildings using large amounts of gaseous fuels) pathway, but there are some gaps in the analysis which limits its usefulness in comparing the overall infrastructure costs of the two options; for example, it does not include the cost of upgrades needed for the gas system to accommodate significant fraction of hydrogen (which would be required to meet the proposed renewable gas loads), nor does it include the cost-savings that could be achieved in the 'electrification' scenario by pruning the gas distribution system and keeping only the most profitable branches. It is also questionable whether opportunities to reduce electrical infrastructure cost by better balancing peak load through smart technologies have been properly captured in this model.

resources and expand demand-side management offerings to offer deep retrofit incentives.
- The BCUC should allow FEI to provide renewable gaseous fuels as a heating source for some existing buildings — but at full marginal cost.
- The province should clarify standards and methodology for utilities to quantify the carbon content of renewable gases and track their environmental attributes to ensure they are not double-counted if traded separately from the molecules. This methodology should be included in the GHGRS and the GGRR before the latter is revised to increase the annual allowable blend of renewable gases in the distribution system above 15%.
- FEI should articulate how the gas delivery system could provide peak heat load rather than base heat load, and work with B.C. to analyse where reliance on gas for heat peaks would be most favorable given electrical capacity constraints and how such value should be monetized, and from this assess where/ when trimming of the gas grid would be economically favorable.
- FEI should present a renewed vision for its business model, shifting from capital investments for the delivery of base heat loads, to focus instead on the production of RNG and hydrogen, the support of gas for transportation, the delivery of deep retrofits, and the provision of low-carbon heat as a service, leveraging both electric and hybrid high-performance systems.

4.2 Areas for future research

- Best practices for the quantification, tracking and trading of environmental attributes such as life cycle emissions for different supplies of renewable gas.
- Additional technical studies to: evaluate the trade-offs between the two principal fuel-switching options (electrification vs. renewable gas) under different policy contexts; evaluate how building owners are likely to respond at the time of replacement of their heating equipment; and measure the rate impact of electrification delivered at scale for things like connection and electrification fees.
- An independent economic analysis of: alternative business models for gas utilities and downsizing risks in response to electrification at scale and deep retrofits for buildings remaining on gas; and modelling for the lowest-cost and lowest-disruption approach to a pruning of the gas grid.
- Investigation of policy mechanisms that government can use to prioritize the direction and use of fuels for certain use cases to avoid undesirable infrastructure lock-in.